ADDENDUM TO

TASK FORCE REPORT

ON

SULPHUR RECOVERY AT ALBERTA GAS PLANTS

ERCB-AE 86-AA

JANUARY 1987

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1 INTRODUCTION

The first phase of the review of Alberta's sulphur recovery requirements was completed with the release of the ERCB/Alberta Environment Task Force Report on Sulphur Recovery in September 1986. The second phase of the review, which is currently under way, allows for a committee made up of representatives of the public, special interest groups, industry, and government to review the Task Force Report and make policy recommendations on sulphur recovery.

The first meeting of the Review Committee took place in October 1986 at which the task force presented its report. This addendum to the Task Force Report was prepared by the task force in response to questions which arose at the October meeting of the Review Committee and to a number of other questions subsequently submitted to the task force by Review Committee participants.

Most of the questions deal with matters of clarification and background of material discussed in the report and with the sensitivity of the economic indicators to variation of the input parameters. The questions and answers have been grouped into several categories for the sake of organizing the addendum. While all of the questions from the various sources are listed, in some cases it was possible to respond to two or more questions with one answer.

The first group of questions deals with background matters such as information respecting existing plants and emissions, as well as forecasts of emissions. The second group of questions pertains to sulphur recovery technology and to what the task force refers to as the IL 80-24 de facto recovery levels. The third group of questions deals with economic matters such as capital and operating costs and an examination of the sensitivity of the economic indicators to variation of plant load factors and product prices. The final group of questions deals with requirements in other jurisdictions.

The source of each question is indicated beside it. Questions labelled as being from the Review Committee are from the October Review Committee meeting. A list of the task force's undertakings from the meeting can be found in Appendix A to the addendum. Questions labelled as Concord are from the special interest groups. These written questions can be found in Appendix B. Questions labelled APIGEC are from the industry representatives of the Alberta Petroleum Industry/Government Environmental Committee and can be found in Appendix C. A final group of questions which was submitted by the Independent Petroleum Association of Canada (IPAC) can be found in Appendix D.

There are references in some of the questions and responses to figures and tables that appeared in the Task Force Report. There are also several new figures and tables that have been prepared for this

addendum. To avoid confusion, we have referred to our new figures and tables as Addendum Figures and Addendum Tables throughout. All other references are to the original tables and figures contained in the Task Force Report issued in September 1986.

2 BACKGROUND

2.1 Historical Plants and Emissions

QUESTION BY CONCORD

Figure 1-2 shows a total of 161 plants covering all sizes. Please confirm that this is the total for the Province.

Are all 161 plants operating under IL 80-24 guidelines? If not, how many are not? Please provide a full break-down of the following parameters for each plant:

- **plant size (inlet sulphur)**
- **% S-recovery**
- **location**
- **projected life**

RESPONSE

There are currently 170 approved acid gas flaring and sulphur recovery plants listed in Alberta according to ERCB records.

Six of these plants are shut down (permanently) and 2 plants were approved but have never been constructed, to give a total of 162 plants operating as of August 1986. The figure of 161 plants was from an earlier compilation. There are also an additional 35 plants which treat very small amounts of H_2S with an iron sponge or equivalent type of process which emit no sulphur to the atmosphere.

Only plants approved since December 1980 are required to meet the IL 80-24 sulphur recovery levels. Seven sulphur recovery plants and 54 acid gas flaring plants have been built since 1980. Approved sulphur inlet rates and required quarterly recovery levels for the seven newest sulphur recovery plants are shown in Addendum Table 2-1.

For the rest of the plants, information regarding approved throughputs, sulphur recovery levels, and emissions is contained in the ERCB Gas Plant List which is available to the public.

Regarding the projected life of existing sour gas plants, we make reference to a 1985 paper by G. J. DeSorcy, Sulphur Recovered from Oil and Gas in Canada, which contains production forecasts for Alberta's sulphur recovery plants. It is our understanding that the forecasts presented in this paper are based on the ERCB's Gas Energy Management Model. This model was also used to develop the forecast of sulphur emissions as presented in the Task Force Report.

ADDENDUM TABLE 2-1 SULPHUR RECOVERY PLANTS BUILT SINCE ISSUANCE OF IL 80-24

PLANT NAME	MAXIMUM APPROVED SULPHUR INLET (t/d)	REQUIRED MINIMUM QUARTERLY SULPHUR RECOVERY EFFICIENCY (%)
Gulf - Banshee (Hanlan)	1 109	98.2
D. M. Wolcott - Brazeau	300	98.0
Petro-Canada - Brazeau	80	98.0
Canadian Occidental - Okotoks	587	98.3[a]
Shell - Progress	13	96.0
Chieftain - Sinclair	261	97.7
Western Decalta - Turner Valley	11	95.0

a 98.3 per cent was set as an annual minimum requirement rather than as a quarterly minimum requirement.

QUESTION BY CONCORD

What are the sizes for each of the 8 plants in the 1000 to 5000 TPD sulphur inlet? (Figure 1-2).

RESPONSE

The sulphur inlet rates for the eight sulphur recovery plants in the 1000 to 5000 t/d size range are shown in Addendum Table 2-2.

ADDENDUM TABLE 2-2 ALBERTA'S EIGHT LARGEST SULPHUR RECOVERY PLANTS

PLANT NAME	MAXIMUM APPROVED SULPHUR INLET RATE (t/d)
Gulf - Banshee (Hanlan)	1 109
Petrogas - Crossfield	1 730
Amoco - East Crossfield	1 834
Chevron - Kaybob	3 629
HBOG - Kaybob (Units 1 & 2)	2 216
Canterra - Strachan	4 660
Shell - Waterton	3 148
Amoco - Windfall	1 225

QUESTION BY REVIEW COMMITTEE

Address question 9, page 2, of the group's 2 October 1986 letter in writing. (This pertains to correlation of discrepancies in sulphur emission data discussed in various sections of the Task Force Report.)

RESPONSE

Reference is made to 1985 Alberta sulphur emission rates of 300, 350, and 330 t/d. ERCB Gas Department records indicate that in 1985 the sulphur emission from all sour gas plants was some 340 t/d. This reconciles reasonably with the 330 t/d shown on Figure 1-3 and the 350 t/d shown on Figure 1-2. In reviewing Figure 1-1, it has come to our attention that the value shown as the 1985 emission rate (approximately 300 t/d) does not include emissions from acid gas flaring plants which were estimated to be about 45 t/d in 1985. For all previous years, the curve shown on Figure 1-1 reflects total emissions from all sour gas plants.

With respect to the emission rate from the group of plants having sulphur inlet rates of less than one t/d, the correct figure is 11 t/d as shown on Figure 1-2. The reference in the text on page 4 to approximately 20 t/d should have read approximately 10 t/d which then corresponds correctly with the reference to emissions from this group forming 3 per cent of total emissions.

QUESTION BY REVIEW COMMITTEE

Provide raw data used to determine (allocation of) reduction in sulphur emissions from 1972 to 1985 (see industry group question 10, page 2).

RESPONSE

In 1972 the amount of sulphur handled was about 18 800 t/d. By 1985 this figure was down to some 14 200 t/d. This is a reduction of about one-quarter.

In 1972 the percentage of sulphur handled which went unrecovered was about 4.25 per cent. By 1985 this figure was down to about 2.40 per cent. This is a reduction of slightly less than one-half (0.44 to be exact).

The combined effect of the downward trends in sulphur handled and percentage of sulphur that went unrecovered was an overall decrease in emissions from 800 t/d in 1972 to 340 t/d in 1985. The portion of this 460 t/d reduction that may be credited to the decrease in sulphur throughput is about 36 per cent (calculated by dividing 0.25 by the

total of 0.25 plus 0.44) while the remaining portion, 64 per cent, may be credited to the increase in sulphur recovery efficiency over the 1972 to 1985 period.

2.2 Emissions Forecast

QUESTION BY REVIEW COMMITTEE

Provide data on the incremental reduction in sulphur emissions associated with the (task force's) two proposed sulphur recovery levels over the forecast period.

RESPONSE

Addendum Figure 2-1 shows the task force's forecast of emissions from future plants under the two proposed alternatives.

QUESTION BY CONCORD

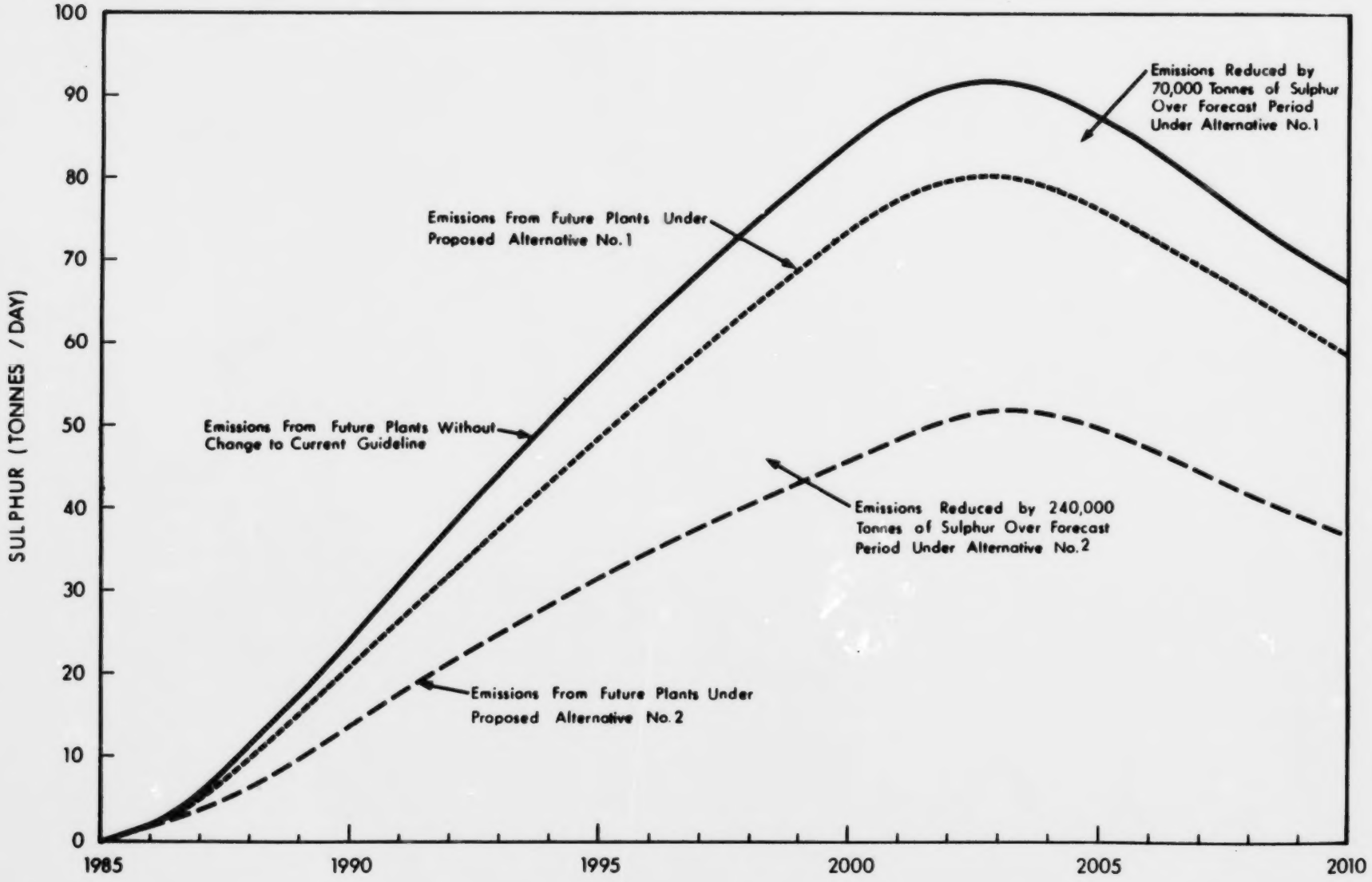
Please superimpose an illustrative plot for Figure 1-3 that includes processing of ultra-high H_2S gas.

Figure 1-3 refers to existing and future plants under IL 80-24. Please superimpose a plot that includes S-emissions from existing plants not covered by IL 80-24.

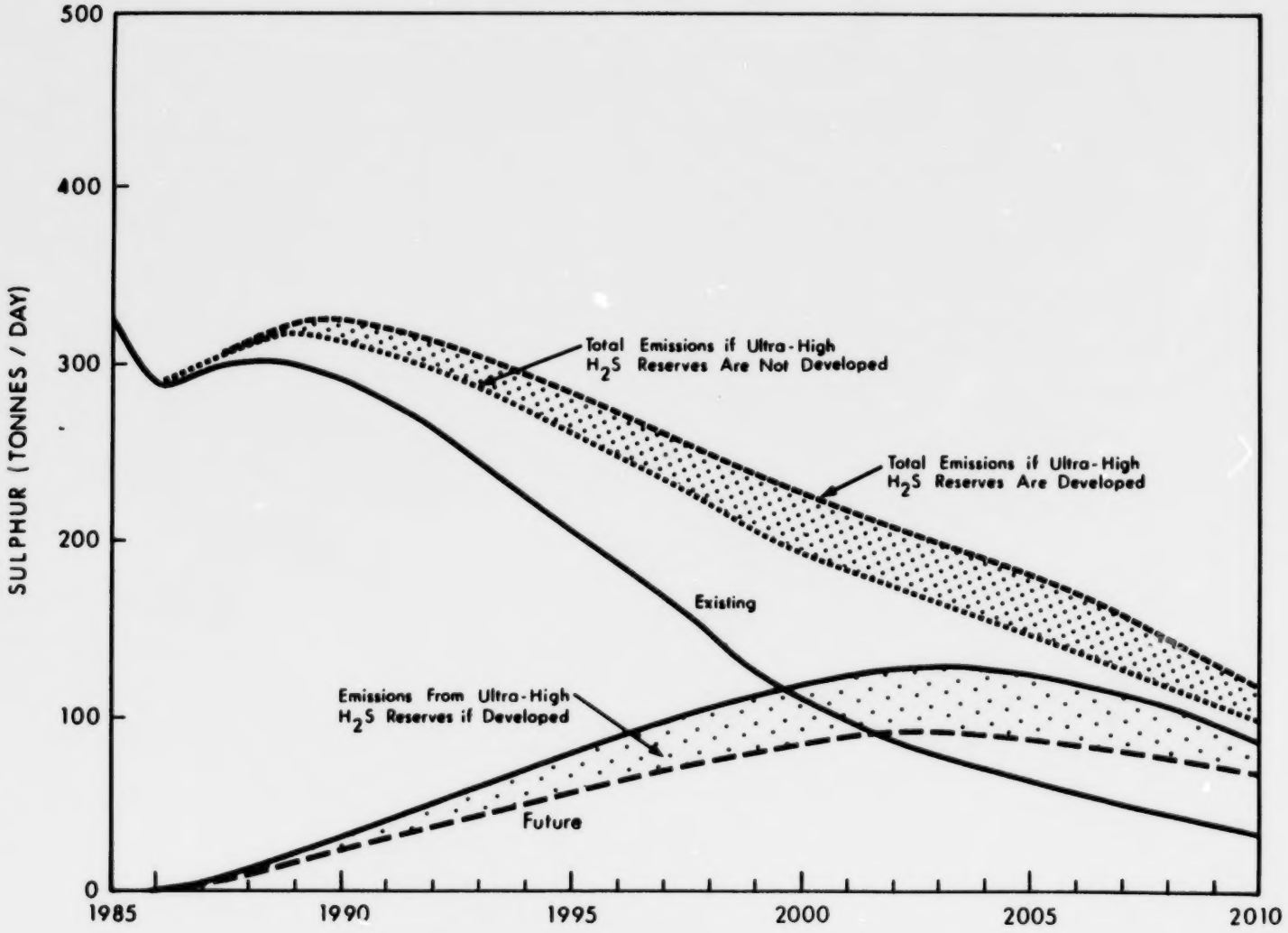
RESPONSE

Addendum Figure 2-2 shows our forecast of emissions from processing Alberta's ultra-high H_2S reserves added to our previous forecast of emissions from existing and future plants. The forecast of emissions from ultra-high H_2S reserves is based on a sulphur production forecast presented in the 1985 paper, Sulphur Recovered from Oil and Gas in Canada, by G. J. DeSorcy. Our emissions forecast assumes an average recovery efficiency of 99 per cent. It should be emphasized that the extent of these reserves and the potential for their development are uncertain at this time and the forecast of emissions from ultra-high H_2S reserves shown on Addendum Figure 2-2 may not occur.

To answer the second part of the question, all existing plants are included in the forecast of emissions in the Task Force Report. All future plants are assumed to meet the requirements of IL 80-24 in the forecast of emissions from future plants.



ADDENDUM FIGURE 2-1 FORECAST SULPHUR EMISSION FROM FUTURE PLANTS UNDER TASK FORCE'S PROPOSED ALTERNATIVES



ADDENDUM FIGURE 2-2 FORECAST SULPHUR EMISSIONS FOR EXISTING AND FUTURE PLANTS INCLUDING ULTRA-HIGH H_2S RESERVES UNDER CURRENT GUIDELINE

2.3 General

QUESTION BY REVIEW COMMITTEE

Expand report in areas that discuss acid gas quality. Draw up trends of acid gas quality in province. Plot new plants since 1980 and include acid gas flaring plants.

RESPONSE

The task force prepared Addendum Figure 2-3 showing acid gas quality and sulphur inlet rate for sulphur recovery plants in Alberta and British Columbia and for acid gas flaring plants that have been built in Alberta since 1980. The data suggest that while the concentration of H_2S in acid gas streams varies quite widely for a given sulphur inlet rate, generally, a trend exists toward higher concentrations of H_2S in the acid gas stream as sulphur inlet rates increase.

British Columbia's three sulphur recovery plants are shown on Addendum Figure 2-3 because reference was made at the Review Committee meeting to the poor quality acid gas being processed at Westcoast Transmission's Pine River plant. We acknowledge that there are cases where lean acid gas is processed at large sulphur recovery plants, but we believe that the data suggest this would not be typical of Alberta sour gas.

QUESTION BY CONCORD

Please supply a plot illustrating allowable SO_2 emission rate (TPD) vs stack effluent flow rate as m^3 per day.

Illustrate on the graph comparison plots for:
- **sour oil processing facilities**
- **coal and coke burning facilities**
- **other, e.g. sulfuric acid plants**

Please supply a plot illustrating maximum allowable H_2S, COS, and CS_2 emission rate vs stack effluent rate.

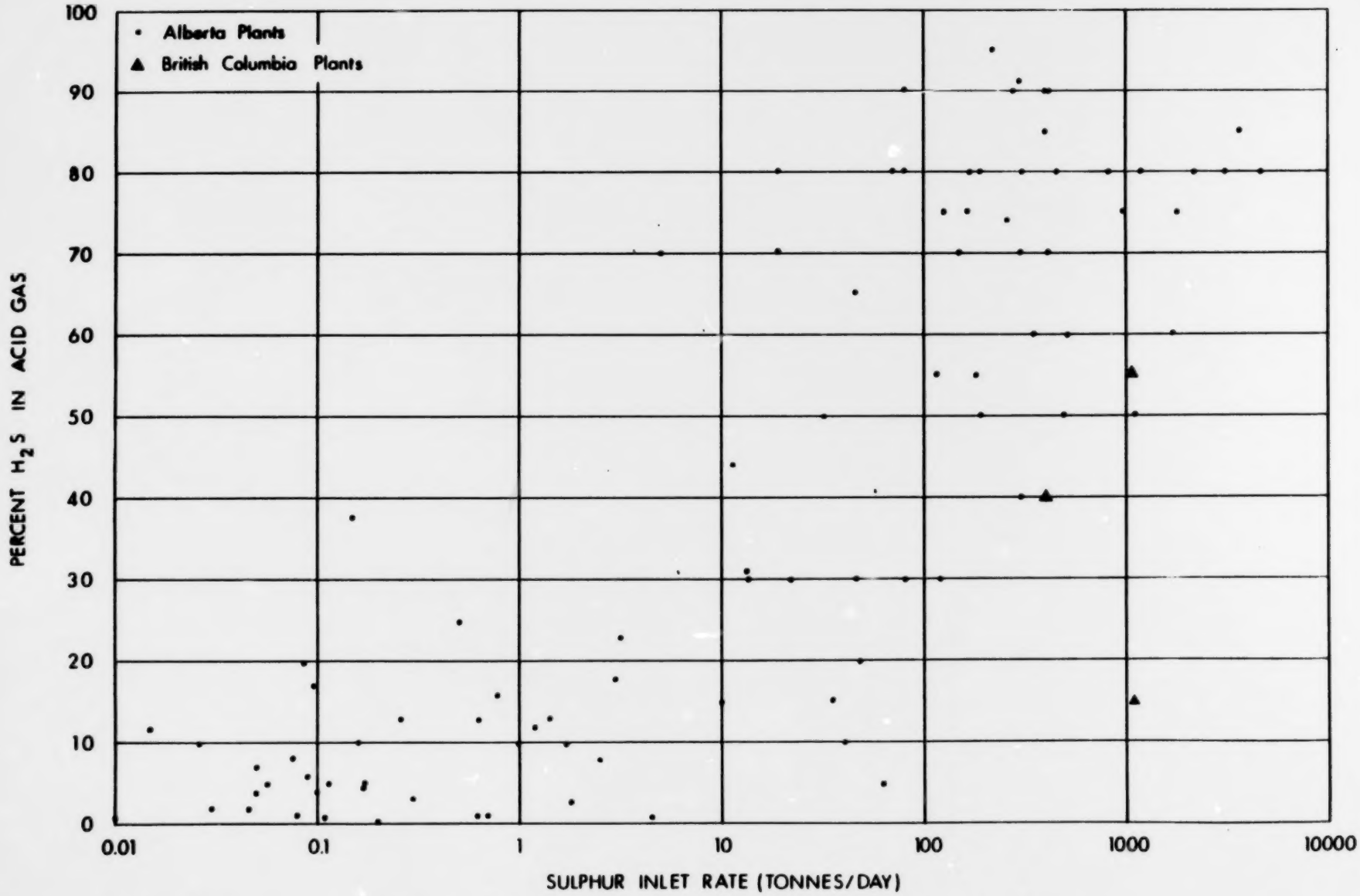
RESPONSE

Addendum Figure 2-4 is a graph of SO_2 emission rates and stack effluent flow rates for Alberta's sour gas processing plants (sulphur recovery plants only), coal-burning thermal power plants, and refineries. Data plotted for sour gas plants fall within the envelope shown on the graph. At gas plants, the SO_2 concentration in the stack effluent is influenced by the quality of acid gas feed and the sulphur recovery efficiency which vary from plant to plant.

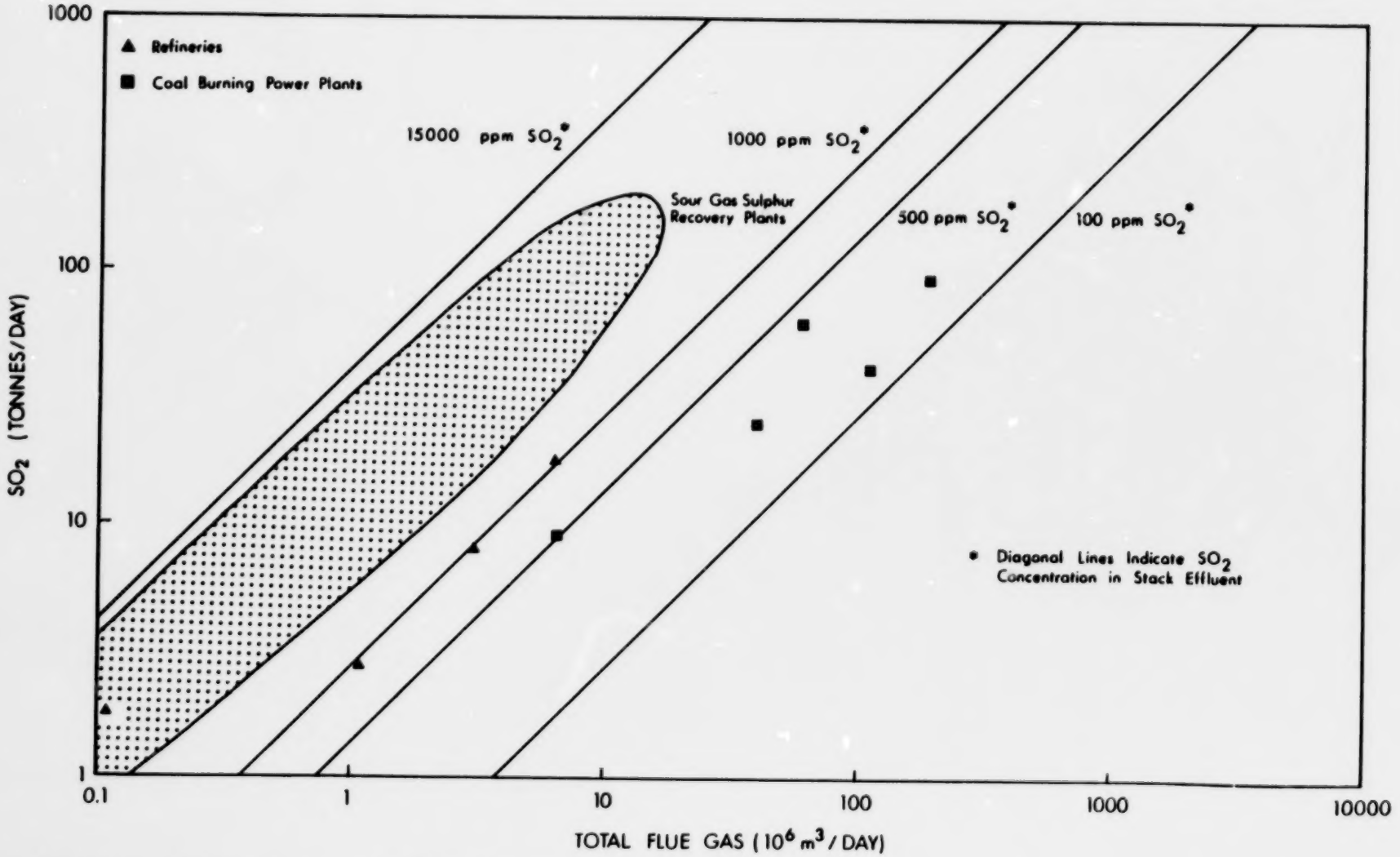
The data plotted for thermal power plants show slightly varying SO_2 concentrations in the stack effluent because of differences in the sulphur content of the coal being burned. Coal with a sulphur content of 0.25 per cent, typical of the coal burned in Alberta, results in stack effluent containing about 400 parts per million (ppm) SO_2.

There are a few sulphuric acid units operating in the province. SO_2 concentrations in the stack effluent for these units are typically between 200 and 300 ppm. On the graph, these would be located in a band slightly to the right of the thermal power plants. Data for refineries suggest SO_2 concentrations in the stack of around 1000 ppm with the exception of one facility which has a higher concentration and falls within the range of sour gas plants.

The allowable concentration of reduced sulphur compounds (H_2S, COS, and CS_2) in stack effluent is set at a maximum of 300 ppm for all sources. For the gas industry, requirements for minimum stack-top temperatures ensure that these compounds are oxidized such that only trace amounts (if any) remain in the stack effluent.



ADDENDUM FIGURE 2-3 ACID GAS QUALITY AND SULPHUR INLET RATES FOR ALBERTA AND BRITISH COLUMBIA SULPHUR RECOVERY PLANTS AND RECENT ALBERTA ACID GAS FLARING PLANTS



ADDENDUM FIGURE 2-4 COMPARISON OF SO_2 EMISSION AND STACK EFFLUENT RATES FOR SOUR GAS PLANTS, REFINERIES AND THERMAL POWER PLANTS IN ALBERTA

3 PROCESS TECHNOLOGY

QUESTION BY REVIEW COMMITTEE

Review the various sulphur recovery technologies described in the report and split out those which are considered available technology compared to proven technology.

RESPONSE

Addendum Table 3-1 lists the sulphur recovery and tail gas clean-up processes that were discussed by the task force in the report and categorizes each process as being either commercially-demonstrated or developing technology. Processes classified as commercially-demonstrated have at least one commercial-scale plant that has operated in the sour gas processing industry or in an industry having similar acid gas makeup.

QUESTION BY REVIEW COMMITTEE

Clarify the intent of the defacto line on the graph on page 59 of report.

RESPONSE

The de facto line as defined by the task force is shown on Addendum Figure 3-1 overlaid on the IL 80-24 graph of minimum recovery requirements.

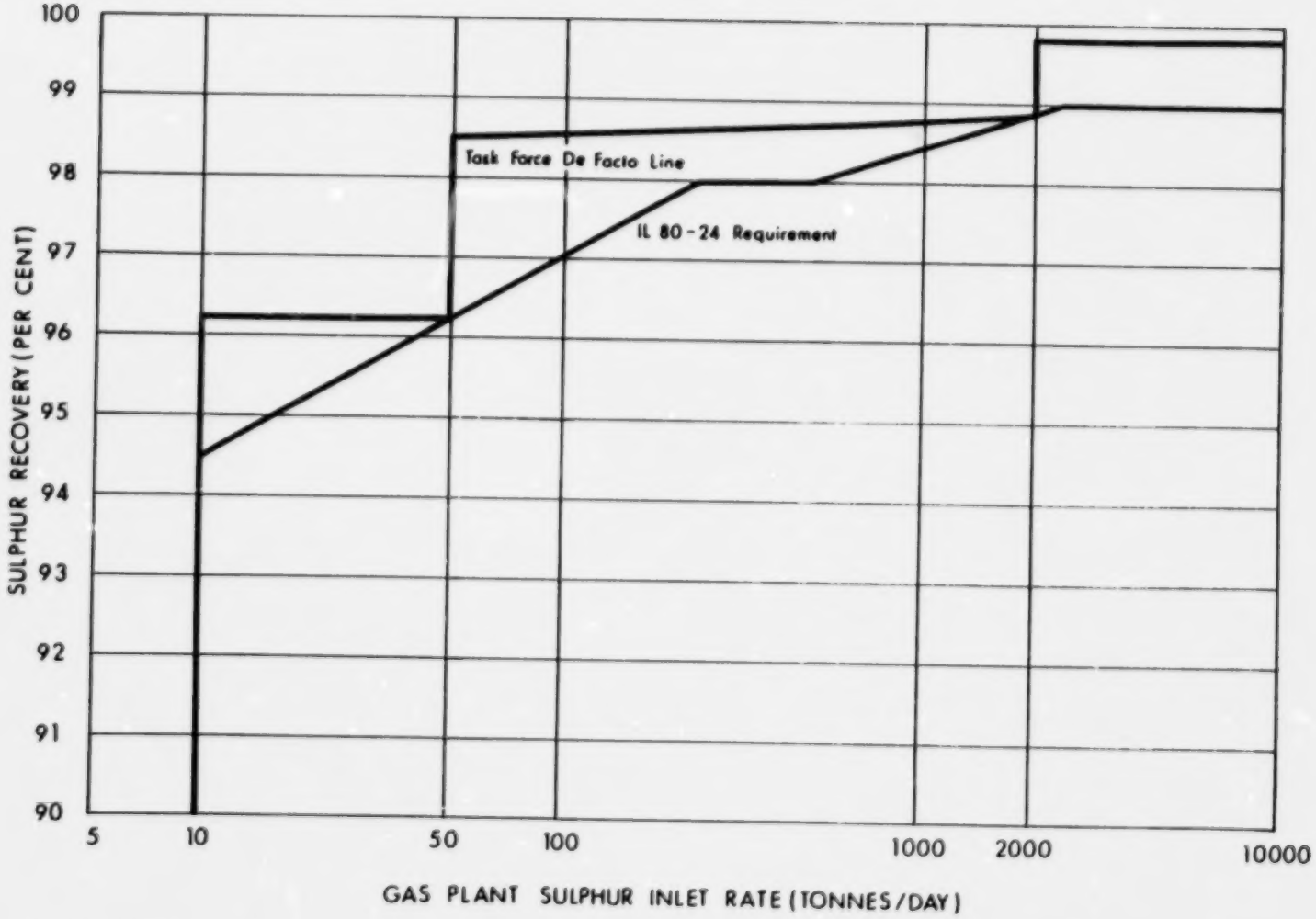
There are three different sections of the de facto line each of which portray the capability, in our opinion, of a distinct type of demonstrated sulphur recovery technology. After our review of sulphur recovery technology we concluded that

- conventional modified-Claus technology (3 stages) is capable of achieving a long-term average recovery efficiency of 96.2 per cent with reasonable quality acid gas,
- sub-dewpoint Claus technology is capable of achieving long-term average recovery efficiencies of 98.5 per cent with reasonable quality acid gas and 98.8 per cent with good quality acid gas,
- tail gas clean up technology of the selective absorption or direct oxidation type treating Claus plant tail gas is capable of increasing long-term average recovery efficiencies to 99.8 per cent overall.

ADDENDUM TABLE 3-1 SULPHUR RECOVERY AND TAIL GAS CLEAN-UP PROCESSES

Commercially-Demonstrated Sulphur Recovery Processes	Developing Sulphur Recovery Processes
Modified-Claus	Linde Claus Plant Oxygen Enrichment
COPE (Claus Oxygen-based Process Expansion)	Kellog Oxydesulphurization (ODS)
MCRC sub-dewpoint Claus	Citrate
Selectox/Recycle Selectox	Budra One-Step Desulphurization
Stretford Sulphur Removal	
Lo-Cat	
Unisulf	
Sulfint	
Stauffer Sulphur Recovery	
Integrated UCAP	

Commercially-Demonstrated Tail Gas Clean-up Processes	Developing Tail Gas Clean-up Processes
Sulfreen sub-dewpoint Claus	Oxysulfreen
Amoco CBA sub-dewpoint Claus	ULTRA
MCRC sub-dewpoint Claus	UCAP
Maxisulf sub-dewpoint Claus	Citrate
IFP Clauspol 1500	Pritchard Cleanair
SCOT (Shell Claus Offgas Treating)	
BSR/MDEA	
BSR/Stretford	
BSR/Unisulf	
BSR/Selectox	
Sulften	
Wellman-Lord	
Ammonium Thiosulphate	



ADDENDUM FIGURE 3-1 TASK FORCE DE FACTO LINE AND IL 80-24 REQUIREMENT

In arriving at the recovery levels described by the de facto line, we first considered the design capability of the three types of technology and then made what we felt to be a reasonable allowance for deviation from design conditions experienced during normal operation. If these recovery levels were going to be viewed as requirements, we believe it would be necessary to reduce them by a further 0.3 per cent, to allow for plant upset conditions, to arrive at an enforcement level.

The three types of recovery technology divide the sulphur inlet axis between 10 t/d and 10 000 t/d into three regions. Between 10 and 50 t/d sulphur inlet, the requirements of IL 80-24 can be achieved using conventional Claus technology. For plants larger than 50 t/d, IL 80-24 requires recovery in excess of the capability of conventional Claus technology. The next level of technology is sub-dewpoint Claus which would be capable of meeting the requirements of IL 80-24 for sulphur inlet rates between 50 t/d and 2000 t/d. Beyond 2000 t/d, we concluded that sub-dewpoint technology could not be expected to meet the IL 80-24 requirement of 99 per cent. It follows, therefore that for sulphur inlet rates greater than 2000 t/d, the next level of technology is necessary, that being selective absorption or an equivalent type of tail gas clean-up process, which we believe would be capable of achieving 99.8 per cent recovery.

The de facto line represents, in our opinion, the sulphur recovery levels achievable today with the types of technology likely to be installed by industry to meet the requirements of IL 80-24. The recovery levels and technologies described by the de facto line represent the base case or starting point in our economic analysis.

It appears to us that conclusions similar to the above were reached by industry when applying for plants since the issuance of the 1980 guideline. Of these plants, two are in the 10 to 50 t/d size range, one of which uses conventional Claus technology and the other uses sub-dewpoint Claus technology. The remainder of the new plants are in the 50 to 2000 t/d size range and all use sub-dewpoint Claus technology.

Industry has suggested that it would be less expensive to achieve the minimum sulphur recovery levels required by IL 80-24 than it would be to achieve the de facto sulphur recovery levels that the task force assumed.

In the case of large plants (greater than 2000 t/d inlet) we believe that the degree of sulphur recovery required under IL 80-24 necessitates the use of tail gas clean-up equipment that is distinctly "add-on", such as a selective absorption unit. We acknowledge that down-sized "add-on" facilities could be used to increase recovery on

only a portion (say 60 per cent) of the sulphur plant tail gas stream and thereby achieve an overall recovery level that would meet the requirements of IL 80-24 but not those shown by the de facto line. In such a case, part of the tail gas would by-pass the tail gas clean-up unit and go directly to the incinerator. Table 4-2 of the Task Force Report shows a sulphur plant capital cost of $144 million for the 2500 t/d plant. Using the above scenario as suggested by industry, we estimate a saving of about $20 million for the 2500 t/d plant to achieve 99 per cent sulphur recovery rather than the de facto 99.8 per cent. From a total project point of view the $20 million constitutes a potential 7 per cent saving in capital which together with the savings in operating cost would be reflected in a somewhat higher rate of return than the 33.7 per cent figure in Table 4-5 of the Task Force Report. We have not calculated that figure.

For plants smaller than 2000 t/d, we believe the requirements of IL 80-24 are likely to necessitate the use of sub-dewpoint Claus technology and the suggestion of by-passing gas has less merit. Because the cost differential between sub-dewpoint and conventional Claus technology is relatively small, we do not see the potential for significant cost savings by treating part of the acid gas stream with a sub-dewpoint process and the remainder with a conventional Claus process.

QUESTION BY REVIEW COMMITTEE

Provide a copy of SKM's written comments on the draft Task Force Report.

QUESTION BY CONCORD

Please supply a copy of the SKM Consulting Ltd. Report.

RESPONSE

Prior to finalization of the Task Force Report, SKM Consulting Ltd. of Calgary was engaged to review, in draft form, sections dealing with process technology and capital and operating costs (sections 3 and 4.3 and Appendix C in the final report). SKM was requested to comment on the completeness of the review of process technology, specifically whether any processes had been excluded that could, in SKM's opinion, be important to the gas processing industry. SKM was also requested to provide its opinion on the reasonableness of the capital and operating cost assumptions made by the task force.

SKM's written comments on the work are contained in Appendix E to this addendum.

4 ECONOMICS

4.1 Capital and Operating Costs

QUESTION BY REVIEW COMMITTEE

Write out assumptions used in determining capital cost of various sulphur recovery processes (re: question 8, page 5 of industry group letter).

QUESTION BY APIGEC

We would like to reserve comment on the capital costs until data from the Task Force on capital investment (item 10 in the October 3 meeting minutes) is available.

RESPONSE

The capital costs used in the economic analysis of selected sulphur plant cases are based largely on the information presented for similar cases in the 1983 MHG report, Investment and Operating Cost Study, Sulphur Recovery Facilities, Natural Gas Processing Industry, Environment Canada. The costs in the MHG report were estimated in 1982. We believe that it is reasonable to use the 1982 figures without escalation to represent 1986 capital costs because of the relatively stagnant economic conditions that have existed in the Alberta gas industry since the early 1980s and the resulting stability in costs of capital projects in the oil and gas industry.

As stated in the MHG report, the capital costs include all engineering, material, and construction fees for the sulphur plant and tail gas clean-up unit, if applicable. As well, installed costs for an incinerator and 76-metre stack are included as a separate component for each case according to the MHG figures. No costs for an incinerator and stack were included for the BAT cases because the tail gas clean-up process is assumed to reduce H_2S concentrations in the offgas to a sufficiently low level that incineration would not be required under normal operation. It should be noted, however, that some type of standby system would be required to burn the Claus plant tail gas during times when the tail gas clean-up unit is non-operational. A reasonable capital cost for a standby system might be about half that of a main incineration and stack system. Inclusion of such costs for the 2500 t/d case would amount to approximately $0.4 million which is less than one-half of one per cent of the total capital cost of the complete sulphur plant.

Costs for sulphur recovery and tail gas clean-up processes not specifically addressed in the MHG report were estimated by reviewing published information on the processes, and comparing that cost information with data for similar processes included in the MHG report.

Capital costs for sulphur forming and handling facilities were included for the 350, 1000, and 2500 t/d cases. Estimates were made for these costs assuming the use of a belt-type process for the 350 and 1000 t/d cases and a tower-type prilling process for the 2500 t/d case.

QUESTION BY REVIEW COMMITTEE

Look at more factors in re-evaluating the economic analysis for plants considered in the 1-5 t/d sulphur recovery range discussed in the report.

RESPONSE

We have reviewed our capital and operating cost estimates for direct oxidation sulphur recovery plants processing between 1 and 10 t/d. Our estimates compare well with recent data submitted to the ERCB by the process licensor in Alberta and with recent applications for small plants where sulphur recovery has been addressed. We conclude that there is no need to adjust the basic capital and operating costs shown in the report.

It is our understanding, however, that the capital costs presented in the report for the 1, 2, 5, and 10 t/d cases do not include winterization costs for the direct oxidation process equipment. We believe that increasing the capital costs by some $100 000 for the 1 and 2 t/d sizes and by $200 000 for the 5 and 10 t/d sizes would allow for the construction of a building to house these relatively small units.

With respect to operating costs, we did not include a cost for disposal of the sulphur by-product where it is considered as a waste in the 1 and 2 t/d cases. A cost of $200/t (see response to next question) is therefore added to the variable operating costs for the 1 and 2 t/d cases.

Adjusted sulphur plant capital and operating costs are shown in Addendum Table 4-1 as well as the recalculated project rates of return and marginal costs.

ADDENDUM TABLE 4-1 RECALCULATED ECONOMIC INDICATORS FOR SMALL PLANTS

Sulphur Inlet	Sulphur Plant Capital Cost	Sulphur Plant Variable Operating Cost	Sulphur Plant Fixed Operating Cost	After-Tax Rate of Return	Marginal Cost
(t/d)	(10^6\$)	(10^3\$/yr)	(10^3\$/yr)	(%)	(\$/t)
1	0.57(0.47)	175(105)	57(54)	14.4(16.5)	1 180(720)
2	0.93(0.83)	300(160)	68(65)	16.5(17.7)	750(540)
5	1.8(1.6)	230(230)	91(88)	18.2(19.1)	240(220)
10	2.7(2.5)	335(335)	123(120)	17.2(18.1)	140(130)

Numbers in parentheses are those which were published in the original Task Force Report.

QUESTION BY REVIEW COMMITTEE

Investigate and comment on environmental cost and impact of disposal of non-saleable sulphur (re: question 5, page 8 of industry group letter).

RESPONSE

Non-marketable sulphur includes dirty and contaminated sulphur from spills, base pads, and off-spec sulphur. Some of this sulphur is cleaned and recovered at gas plants or gathered, stored, and reclaimed at specific locations in the province. The waste material remaining after sulphur is reclaimed is a solid material containing 4 to 10 per cent sulphur, and must be disposed of in an acceptable manner.

Acceptable disposal methods of materials containing sulphur include

(a) landfill on site,

(b) landfill off site, and

(c) landfarming on or off site.

The "Guidelines for the Disposal of Sulphur Containing Solid Wastes" published by the Department of the Environment provides the necessary guidance for the protection of soil and groundwater. Landfilling on site needs to be specifically approved by the Department. Off site disposal facilities in the form of municipal landfills capable of accepting industrial wastes are available across the province.

Assuming the frequency of occurrence of small gas plants processing 2 to 5 t/d inlet sulphur remains the same as in the past and the quantity of such sulphur produced follows past history, we can estimate that some 20 to 30 t/d sulphur may be generated from 12 to 15 plants in the next 10 to 15 years, if sulphur recovery is required for these plant sizes. Compared to the quantities of waste material from the reclamation of base pads, the amount of waste sulphur from the small sour gas plants will not pose an environmental problem nor have a significant environmental impact. Also, if enough direct oxidation type sulphur becomes available in an area, the operation of a central facility to melt and purify the sulphur for sale might be justified.

For a typical plant of 2 to 5 t/d sulphur inlet, the total cost for the disposal of non-marketable sulphur to a municipal landfill is estimated to be between $150/t and $200/t of solid sulphur. This cost would depend on the

(a) concentration of solid sulphur in the slurry, about 10 to 40 per cent,

(b) distance to landfill site (trucking cost), and

(c) landfill charges, if any.

For disposal on site, the cost would depend on

(a) the cost to construct on site landfill,

(b) the cost of limestone delivered to the site, and

(c) the placement cost of the sulphur and the limestone.

On site disposal is expected as well to be between $150/t and $200/t of sulphur.

QUESTION BY CONCORD

On page 33 it is assumed that direct oxidation processes are considered to be the least costly to apply and are capable of achieving the highest S-recovery levels. Please illustrate in a table comparison costs (capital and operating) for direct oxidation processes with other representative processes. Illustrate costs for 50, 350, and 2500 t/d S-inlet examples.

RESPONSE

Direct oxidation processes appear to be the least costly to use for sulphur recovery at small plants, ie. up to about 10 to 15 t/d sulphur inlet. For comparison purposes, the cost of using either the Claus or Selectox processes for sulphur recovery at small plants is shown in Addendum Table 4-2. Also, the cost of using a direct oxidation type process for a 50 t/d plant is shown. (This cost estimate assumes the use of 5 parallel 10 t/d units.)

QUESTION BY APIGEC

> **Using published refinery and pipeline cost indexes, increase the capital investment from the 1981-82 estimates to current (1987) values.**

RESPONSE

Starting with 1982, we have reviewed the progression of the Nelson Refinery Construction Cost Index and the OGJ-Morgan Gas Pipeline Cost Index. From 1982 to mid-1986, the refinery cost index increased by a total of 10.6 per cent. From 1982 to the end of 1985, the pipeline cost index increased by a total of 5.8 per cent. (The index number for year-end 1985 is the last available for the OGJ-Morgan index.) We have assumed that there would be only minimal escalation of these indices from mid-1986 to the current year.

We note that while these indices could be an indicator of Alberta's plant construction costs, both are calculated using American data and are therefore a reflection of the level of economic activity in the United States rather than economic activity in Canada or more specifically, Alberta. We believe that increasing the capital cost figures by 10 per cent as suggested by these indices will result in capital cost figures which are somewhat overstated for Alberta.

If the above-noted indices are applied, the capital costs of the various sulphur recovery plants and tail gas clean-up units for the 50 t/d and larger cases would be increased by 10 per cent.

Recalculated project rates of return and marginal costs of sulphur recovery for the 50 t/d and larger cases using the increased capital costs are shown in Addendum Tables 4-3a and 4-3b.

ADDENDUM TABLE 4-2 CAPITAL AND OPERATING COSTS FOR SMALL PLANTS

1	2	3	4	5	6
Sulphur Inlet	Process	Capital Cost	Var. Oper. Cost @ Design Rate	Fixed Oper. Cost	Net Fuel Gas Credit @ Design Rate
(t/d)		(10^6 $)	(10^3 $/yr)	(10^3 $/yr)	(10^6 m^3/yr)
2	Direct Oxidation	0.83	160	65	-
2	Recycle Selectox	2.53	13	116	(0.25)
5	Direct Oxidation	1.60	230	88	-
5	Recycle Selectox	3.44	26	143	(0.61)
10	Direct Oxidation	2.50	335	120	-
10	Recycle Selectox	4.47	62	174	(1.24)
10	Claus	3.66	56	150	(0.34)
50	Direct Oxidation	12.5	1 675	600	-
50	Claus	4.6	237	264	2.7

ADDENDUM TABLE 4-3a CALCULATED AFTER-TAX RATES OF RETURN UNDER ALTERNATIVE RECOVERY LEVELS[a] (PLUS 10% CAPITAL COST CASE)

Sulphur Inlet (t/d)	IL 80-24 (%)	Intermediate Technology (%)	Best Available Technology (%)
50	16.8 (17.5)	16.7 (17.4)	14.2 (14.5)
350	27.6 (29.1)	26.8 (28.3)	24.2 (25.1)
1 000	33.4 (35.3)	N/A[b]	30.7 (32.6)
2 500	31.6 (33.7)	N/A[c]	N/A[c]

a These are after-tax rates of return consistent with the assumptions described in sections 4.1, 4.2, and 4.3 of the Task Force Report.

b In this case, the intermediate technology was more costly than BAT and was, therefore, ignored.

c For the 2500 t/d case, IL 80-24 is equivalent to BAT.

Numbers in parentheses are those which were published in the original Task Force Report.

ADDENDUM TABLE 4-3b MARGINAL COSTS PER TONNE OF SULPHUR EMISSIONS ABATEMENT[a]
(PLUS 10% CAPITAL COST CASE)

Sulphur Inlet (t/d)	IL 80-24 to Int ($/t)	Int to BAT ($/t)	IL 80-24 to BAT ($/t)
50	29 (20)	3 100 (2900)	1 080 (1000)
350	3 500 (3250)	1 280 (1190)	1 480 (1380)
1 000	N/A	N/A	730 (680)
2 500[b]	N/A	N/A	N/A

a These calculations represent the constant dollar value (as of 1987) of the net costs of additional sulphur recovery over and above commodity value of sulphur ($135/t).

b Since IL 80-24 already requires BAT, there are no additional marginal costs to consider. The task force notes, however, that the marginal cost in going from subdewpoint (98.8%) technology to BAT (99.8%) is about the same as in the 1000 t/d case.

Numbers in parentheses are those which were published in the original Task Force Report.

QUESTION BY IPAC

> **The non-inclusion of exploration costs in your rate of return calculation is misleading to the public. These figures indicate very high after tax ROR of double or more of bank interest. You admit that risk has to be applied yet you did not apply it. As Alberta exploration is in a mature state, the discoveries are smaller (1 to 3 wells, 5 to 20 BCF) of 1 to 10 per cent H_2S gas. These require detailed seismic work and complex geological examination, which is a significant portion of most projects, plus the proportionate cost of drilling dry holes. We would suggest that the after tax ROR could be lowered 5 to 10 per cent (before sulphur plant addition) to a rate closer to "bank rates" and then if the differential ROR for sulphur recovery is taken off then the ROR could be below the bank rate of 10 per cent. This would of course depend on the success ratio of a company, remoteness of the area, reserves found, etc. which really means it is very dangerous to present a typical case - What is typical?**

RESPONSE

> "We wish to stress that the projects profiled in this report assume that the reservoir has already been discovered and to some extent delineated. Thus, the task force ignored exploration costs and exploration drilling success rates. As a result the rates of return we calculated are exaggerated."

This statement, taken from page 31 of the Task Force Report was intended to tell the reader that exploration costs had not been considered in our economic analysis and that the rates of return calculated for our projects appeared to be high for that reason.

The reason that exploration costs were excluded from our analysis is well brought out by the last sentence of IPAC's question itself. With all of the variables involved, the assignment of exploration costs to each of our projects would have been arbitrary at best. We are of the opinion that the economic impact of the proposed new guidelines would not be significant enough to cause a change in exploration drilling budgets or exploration plans. Thus, the relevant business criteria begin when a corporation is faced with a decision to proceed or not to proceed with the development of some previously delineated reserve of sour gas. At such a point, the previously incurred costs for exploration are totally irrelevant to the decision of whether or not to proceed with a project. Thus, we did not include them.

We also note that the "bank rate" used by IPAC is a before-tax rate. Thus, the after-tax calculations in our analyses are not appropriately compared to a before-tax "bank rate" of 10 per cent.

QUESTION BY APIGEC

Increase the capital investment by 50 per cent to cover exploration costs which might approximate full cycle economics.

RESPONSE

We cannot comment further on the accuracy of such an assumption nor the utility of including such costs.

In response to the request we have increased the total capital costs by 50 per cent for the 5 t/d, the 350 t/d, and the 1000 t/d projects and recalculated the rates of return. The results are presented in Addendum Table 4-4.

Although the sulphur plant costs are assumed to be increased by 50 per cent as part of the total capital cost, it would not be reasonable to recalculate marginal costs based on these arbitrary figures.

QUESTION BY APIGEC

Additional detail on operating cost assumptions and, in particular, the treatment of fuel gas in the analysis is also requested.

RESPONSE

With some modification, our variable operating costs for the sulphur plants were based largely on the calculated utility and chemical requirements presented in the MHG report, as well as on the assumptions described in that report regarding utility and chemical prices.

In the area of steam credit and fuel gas consumption we deviated from the MHG approach by assigning a fuel gas equivalency to the high-pressure, medium-pressure, and low-pressure steam production from the sulphur plant, rather than assigning a monetary credit. The equivalency was based on the energy value of the produced steam and an assumed 75 per cent efficiency of producing that steam from fuel gas. Recognizing that in some plants the need for steam may be less than the steam production from the sulphur plant, the task force arbitrarily assumed that one-half of the high-pressure and medium-pressure steam production could be used and therefore was equated to a fuel gas credit. The remainder of the high-pressure and medium-pressure steam and all of the low-pressure steam was assumed to

ADDENDUM TABLE 4-4 CALCULATED AFTER-TAX RATES OF RETURN UNDER ALTERNATIVE RECOVERY LEVELS[a] (PLUS 50% CAPITAL COST CASE)

Sulphur Inlet (t/d)	IL 80-24 (%)	Intermediate Technology (%)	Best Available Technology (%)
50	19.9 (24.9)	N/A[b]	16.9 (19.1)
350	22.2 (29.1)	21.7 (28.3)	20.2 (25.8)
1 000	26.7 (35.3)	N/A[b]	25.1 (32.6)

a These are after-tax rates of return consistent with the assumptions described in sections 4.1, 4.2, and 4.3 of the Task Force Report.

b In these cases, the intermediate technology was more costly than BAT and was, therefore, ignored.

Numbers in parentheses are those which were published in the original Task Force Report.

have no value. The calculated fuel gas credit from the sulphur plant is then assigned the same value and treated in the same fashion as other marketable gas production at the plant.

The fixed component of our sulphur plant operating costs included an annual allowance for maintenance and repair of 3 per cent of the capital costs. Salaries and wages of operating personnel were as per the MHG report.

Variable operating costs for direct oxidation type sulphur plants considered for the 1 to 10 t/d sizes were based on information published by the process licensor. These costs are for chemical and utility usage. Fixed operating costs for these units were calculated the same way as for the larger sulphur recovery plants.

A detailed analysis of operating costs for the wells, gathering system, and the gas conditioning plant was not undertaken. We assumed an annual operating cost equal to 10 per cent of the capital cost for the facilities. This operating cost was assumed to be split equally between the variable and fixed components. We view the accuracy of estimated "front-end" operating costs to be less important in our analyses than the costs associated with the sulphur plants. The front-end costs affect the project rate-of-return calculations but are not a factor in the marginal cost analysis.

QUESTION BY CONCORD

Please supply a copy of the MHG Report.

RESPONSE

A copy of the MHG report that was referred to in the Task Force Report as a source document of capital and operating cost information has been sent to Concord. We understand that the APIGEC technical group also has a copy of the report.

4.2 Sensitivity Cases Varying Plant Load Factors and Product Price Forecasts

QUESTION BY REVIEW COMMITTEE

Evaluate the seven plants built since 1981 and provide data on actual plant load factors (re: question 9, page 5, of industry group letter). Industry to provide its estimates of load factors so Task Force can do sensitivity studies on the impact of different load factors.

QUESTION BY APIGEC

Reduce the plant load factors to 65 per cent and 50 per cent to better represent actual situations.

QUESTION BY IPAC

Load factor of 85 per cent is very high. Most contracts require 20 to 25 per cent additional deliverability to be available for peak days. We suggest a load factor in the 70 to 75 per cent range to be more realistic (perhaps look at actual plant statistics).

QUESTION BY CONCORD

Please test the sensitivity of the model to variations in the following input data. For calculation purposes, consider each variable independently.

- Initial year's production held constant for 3 years, increased by 5 per cent in the 4th year, held constant to 6th year, then reduced by 5 per cent in 7th year, and by 10 per cent of a declining balance after. (Examine for 50, 350, and 2500 t/d S-inlet cases and recalculate ROR's in Table 4-5 for these cases.)

RESPONSE

There was considerable discussion at the Review Committee meeting regarding the appropriateness of our assumption of an 85 per cent load factor for capacity utilization in our economic analysis cases. As requested, we looked at historical production data for the seven sulphur recovery plants built since 1980 and calculated annual average load factors for each plant as shown in Addendum Table 4-5. We also looked at processing capacity utilization on a province-wide basis and determined that while the amount of gas processed in 1985 was only marginally greater than the amount processed in 1973, installed processing capacity increased by roughly 50 per cent over the same period. As a provincial average, capacity utilization has declined from 70 per cent in 1973 to about 50 per cent in 1985. The task force believes that the overall load factor decline that has occurred since the early 1970s was caused partly by declining deliverability of fields serving older plants but was also caused by additions of capacity to process new gas reserves in anticipation of continued gas market growth. We believe that under a deregulated system of gas marketing in which producers and consumers arrange sales contracts directly, producers are more likely to be able to optimize the use of existing capacity and plan for the addition of new capacity to the extent that the utilization of plant capacity will increase.

ADDENDUM TABLE 4-5 PLANT LOADING AT SULPHUR RECOVERY PLANTS BUILT UNDER IL 80-24 GUIDELINE
(PER CENT UTILIZATION OF APPROVED CAPACITY)

Year	Chieftain/ Sinclair	Gulf/ Banshee	D.M. Wolcott/ Brazeau River	Western Decalta/ Turner Valley	Petro-Canada/ Brazeau River	Shell/ Progress	Canadian Occidental/ Mazeppa
1982	22.2						
1983	16.6	32.9 (Mar-Dec)					
1984	23.9	35.0	66.0 (May-Dec)				
1985	25.9	45.1	86.1	35.6 (June-Dec)	51.4 (July-Dec)	53.1 (Oct-Dec)	
1986	24.9 (Jan-Aug)	30.2 (Jan-Aug)	79.4 (Jan-Aug)	67.8 (Jan-Aug)	91.3 (Jan-Aug)	56.9 (Jan-Aug)	31.0 (June-Aug)

With respect to the sensitivity cases we selected from the various suggested load factors, rates of 60 and 70 per cent to test the sensitivity of the economic indicators to load factor. For comparison purposes, note that with the production schedule selected for our original economic analyses, that is 85 per cent capacity utilization for a 350-day operating year (81.5 per cent over 365 days) for the first 5 years followed by a 15-year life with a 10 per cent decline in throughput each year, the average load factor over the plant's life is in the order of 50 per cent. The initial load factor of 85 per cent was selected to reflect typical contractual conditions which normally require a plant to be able to meet a peak day requirement in excess of the average day (85 per cent corresponds to a peak day rate of approximately 1.2 times the average day rate). The effect of reduced initial production rates associated with the lower load factors on the production schedule for our plants is shown in Addendum Figure 4-1 for the 1000 t/d case. As can be seen, after the first 6 or 7 years of the project, the production rates are similar under all three assumed load factors. We acknowledge, however, that in the economic analysis, the initial years are the most important. Recalculated project rates of returns and marginal costs for our 5 t/d, 350 t/d, and 1000 t/d cases are presented in Addendum Table 4-6(a) and 4-6(b).

QUESTION BY REVIEW COMMITTEE

Do sensitivity studies on the impact of different product prices. The Industry and Special Interest groups each agreed to provide alternative price scenarios to the Task Force.

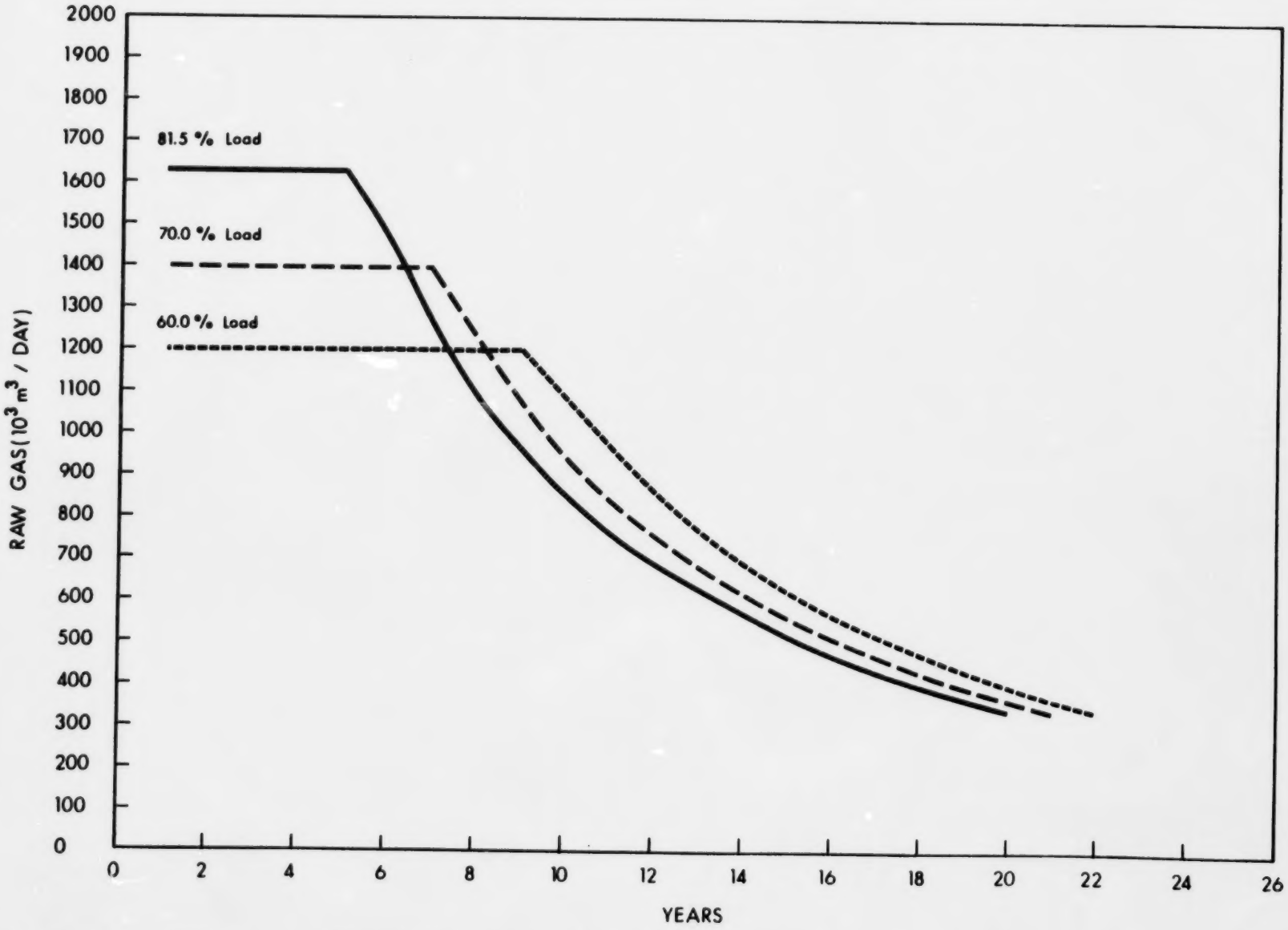
QUESTION BY CONCORD

Please test the sensitivity of the model to variations in the following input data. For calculation purposes, consider each variable independently.

- **product prices increase at 2.5 to 7.5 per cent per year.**
- **fixed and variable operating costs increase at 2.5 to 7.5 per cent per year.**

QUESTION BY APIGEC

Reduce product prices to current level with prices held constant for 2 years increasing at 5 per cent per year through the project life. APIGEC would like confirmation of the current prices that will be used.



ADDENDUM FIGURE 4-1 PRODUCTION SCHEDULES UNDER VARYING INITIAL LOAD FACTORS
(Task force 1000 tonnes/day sulphur plant case)

ADDENDUM TABLE 4-6a CALCULATED AFTER-TAX RATES OF RETURN UNDER ALTERNATIVE RECOVERY LEVELS[a] (LOAD FACTOR SENSITIVITY CASES)

Sulphur Inlet (t/d)	Initial Load Factor (%)	IL 80-24 (%)	Intermediate Technology (%)	Best Available Technology (%)
5	81.5	24.9	N/A[b]	19.1
	70.0	22.5	N/A[b]	17.0
	60.0	20.4	N/A[b]	15.3
340	81.5	29.1	28.3	25.8
	70.0	25.8	25.1	22.9
	60.0	23.2	22.5	20.5
1 000	81.5	35.3	N/A[b]	32.6
	70.0	31.7	N/A[b]	29.0
	60.0	28.3	N/A[b]	25.7

a These are after-tax rates of return consistent with the assumptions described in sections 4.1, 4.2, and 4.3 of the Task Force Report.

b In these cases, the intermediate technology was more costly than BAT and was, therefore, ignored.

ADDENDUM TABLE 4-6b MARGINAL COSTS PER TONNE OF SULPHUR EMISSIONS ABATEMENT[a]
(LOAD FACTOR SENSITIVITY CASES)

Sulphur Inlet (t/d)	Initial Load Factor (%)	IL 80-24 to Int ($/t)	Int to BAT ($/t)	IL 80-24 to BAT ($/t)
5	81.5	N/A	N/A	220
	70.0	N/A	N/A	260
	60.0	N/A	N/A	300
340	81.5	3 250	1 190	1 380
	70.0	3 500	1 280	1 480
	60.0	4 070	1 480	1 720
1 000	81.5	N/A	N/A	680
	70.0	N/A	N/A	860
	60.0	N/A	N/A	1 000

a These calculations represent the constant dollar value (as of 1987) of the net costs of additional sulphur recovery over and above the commodity value of sulphur ($135/t).

QUESTION BY IPAC

$1.60/GJ - not in todays deregulated world - Price at WH of $1.00 - $1.25/GJ is more normal, at least for the present and probably for as long as surplus test exists.

$29/bbl condensate? - We believe $20 is more realistic. Sulphur prices have also dropped 8 to 10 per cent over the last 2 months on export markets and sulphur block recovery slowed although in the long run prices may hold. We would like more detailed information on economic cases.

RESPONSE

We consider that the only substantive comment regarding the task force's price forecasts was on the price of pentanes plus. We agree that its initial price of $\$185/m^3$ is too high, and that a price between $125 and $\$145/m^3$ would be more appropriate. However, we considered eliminating the pentanes plus production altogether and found that even this had only a small impact on rates of return. Therefore, with the minimal impact that a price reduction would have on rates of return (less than 1 per cent), we chose not to rerun the computer model. As well, the prices quoted by IPAC are wellhead prices, while our prices are for processed gas at the plant gate. Finally, our price forecasts make no allowance for real price increases over the forecast period which, in our opinion is a conservative assumption.

The task force is satisfied that its gas price and sulphur price forecasts are appropriate and, indeed, the gas price forecast tends to the conservative end of price forecasts which have been published (eg. ERCB Report 86-A Requirements Report). Thus, the task force chose not to generate new results based on alternative price forecasts.

4.3 General

QUESTION BY REVIEW COMMITTEE

Provide a list of economic parameters considered in the report if the representatives for the industry members of APIGEC (industry group) identifies what specific data is wanted.

QUESTION BY CONCORD

Are the assumptions on page 33 the only assumptions used in the model? If not, please provide details.

RESPONSE

We did not receive any specific requests for information on economic parameters or assumptions other than those dealing with capital and operating costs which have been answered in section 4.1.

QUESTION BY CONCORD

What are the correct data for columns 3 and 4 in Table 4-7?

RESPONSE

The corrected marginal cost figures are shown in the following Addendum Table 4-7. Note the changes under the column IL 80-24 to BAT, $2920/t becomes $1000/t and $4440/t becomes $1380/t.

QUESTION BY REVIEW COMMITTEE

Make available all computer economic evaluation runs.

RESPONSE

We did not receive any requests to examine the output from our runs of the economics model. This option remains available.

QUESTION BY IPAC

Percentage difference should be presented

Example 1) ROR difference for 1 t/d is 25 per cent versus 17 per cent for 50 t/d and 8 per cent for 1000 t/d (Table 4-5).

Example 2) Difference of pre-tax revenue (Table 4-6). Revenue per cent difference for 1 t/d is 39 per cent versus 22 per cent for 10 t/d, 6 per cent for 1000 t/d (also see attached cost indicators).

RESPONSE

Changes in rates of return and pre-tax net revenues are expressed as percentages in the following Addendum Tables 4-8 and 4-9.

ADDENDUM TABLE 4-7 REVISED MARGINAL COSTS PER TONNE OF SULPHUR EMISSIONS ABATEMENT[a]

Sulphur Inlet (t/d)	IL 80-24 to Int ($/t)	Int to BAT ($/t)	IL 80-24 to BAT ($/t)
1	N/A	N/A	720
2	N/A	N/A	540
5	N/A	N/A	220
10	N/A	N/A	130
50	20	2 900	1 000
350	3 250	1 190	1 380
1 000	N/A	N/A	680
2 500[b]	N/A	N/A	N/A

a These calculations represent the constant dollar value (as of 1987) of the net costs of additional sulphur recovery over and above commodity value of sulphur ($135/t).

b Since IL 80-24 already requires BAT, there are no additional marginal costs to consider. The task force notes, however, that the marginal cost in going from subdewpoint (98.8%) technology to BAT (99.8%) is about the same as in the 1000 t/d case.

ADDENDUM TABLE 4-8 CALCULATED AFTER-TAX RATES OF RETURN UNDER ALTERNATIVE RECOVERY LEVELS AND PER CENT CHANGE

1	2	3	4	5	6
Sulphur Inlet	IL 80-24	Change	Intermediate Technology	Change	Best Available Technology
(t/d)	(Absolute %)	(%)	(Absolute %)	(%)	(Absolute %)
1	22.1	-	N/A	-25	16.5
2	22.8	-	N/A	-22	17.8
5	24.9	-	N/A	-23	19.1
10	24.1	-	N/A	-25	18.1
50	17.5	-1	17.4	-17	14.5
350	29.1	-3	28.3	- 9	25.8
1 000	35.3	-	N/A	- 8	32.6
2 500	33.7	-	N/A	-	N/A

ADDENDUM TABLE 4-9 DISCOUNTED REVENUES AND COSTS UNDER ALTERNATIVE RECOVERY LEVELS AND PER CENT CHANGE

1		2	3	4	5	6	7	8
Sulphur Inlet Rate (t/d)		IL 80-24 (10^3 $)	Intermediate Technology (10^3 $)	Change (3-2) (10^3 $)	Change (%)	BAT (10^3 $)	Change (5-3) (10^3 $)	Change (%)
	Pre-tax revenue	10 521				10 521		
1	Production costs	6 845	N/A			8 294		
	Pre-tax net revenue	3 676				2 227	- 1 449	-39
	Pre-tax revenue	14 588				14 588		
2	Production costs	8 858	N/A			11 023		
	Pre-tax net revenue	5 730				3 565	- 2 165	-38
	Pre-tax revenue	21 041				22 307		
5	Production costs	11 677	N/A			15 123		
	Pre-tax net revenue	9 364				7 184	- 2 180	-23
	Pre-tax revenue	28 055				30 586		
10	Production costs	16 099	N/A			21 216		
	Pre-tax net revenue	11 956				9 370	- 2 586	-22
	Pre-tax revenue	54 624	54 941			55 095		
50	Production costs	40 744	41 106			45 039		
	Pre-tax net revenue	13 880	13 835	- 45	0	10 056	- 3 779	-27
	Pre-tax revenue	170 838	170 910			170 613		
350	Production costs	85 088	87 257			94 602		
	Pre-tax net revenue	85 750	83 663	-2 087	-2	76 011	- 7 652	- 9
	Pre-tax revenue	391 317				392 280		
1000	Production costs	168 291	N/A			181 780		
	Pre-tax net revenue	223 026				210 500	-12 526	- 6
	Pre-tax revenue	976 076						
2500	Production costs	438 094	N/A			N/A	N/A	
	Pre-tax net revenue	537 982						

QUESTION BY IPAC

Concern over amount

Page 37 Paragraph 2:
$5MM may not be missed - is a very dangerous statement in these times.

RESPONSE

The paragraph referred to in IPAC's question/statement was intended to describe common interpretations of one of the economic indicators that was considered, namely, the change in discounted revenues and costs associated with increasing levels of sulphur recovery. We suggested that this parameter provides an indication of the degree of affordability of increased sulphur recovery.

Looking at the example cited for our 350 t/d case, one could compare the $5 million reduction in corporate income with the approximate $33 million pre-tax net revenue from the project, both of which would occur over the 21-year life of the project. The $5 million therefore would represent roughly a 15 per cent reduction in corporate revenues from the project. We concluded that the magnitude of the change in this example would not likely be so significant that the project would not proceed. However, as also stated in the referenced paragraph, this conclusion does <u>not</u> necessarily lead to the conclusion that a higher level of sulphur recovery <u>should</u> be required.

5 SULPHUR RECOVERY REQUIREMENTS IN OTHER JURISDICTIONS

QUESTION BY REVIEW COMMITTEE

Compare EPA sulphur recovery guidelines and IL 80-24. Clarify areas where EPA guideline is higher than IL 80-24 and where IL 80-24 is higher than EPA.

RESPONSE

A comparison of the EPA requirements with Alberta's IL 80-24 is shown in Addendum Figure 5-1. For this comparison, we have superimposed the IL 80-24 curve on the EPA requirements for ongoing operation. Note that it is generally understood that the IL 80-24 requirements apply for good quality acid gas streams (greater than 40 per cent H_2S). IL 80-24 should therefore be compared mainly with the EPA's uppermost band that is required for acid gas streams with at least 50 per cent H_2S. The plant size ranges where Alberta is either higher or lower than the EPA requirements can be seen from the figure. Below 2 t/d sulphur inlet, neither guideline requires sulphur recovery. Between 2 and 10 t/d, the EPA requires sulphur recovery levels ranging from 74 per cent to about 93.5 per cent, depending on sulphur inlet and acid gas quality. IL 80-24 requires no sulphur recovery over this size range. Between 10 t/d and 250 t/d IL 80-24's requirements exceed those of the EPA. The difference is about 1 per cent at 10 t/d when IL 80-24 is compared to the EPA's requirement for the best quality acid gas. For sulphur inlet rates between 250 and 500 t/d, IL 80-24 requirements are higher than the EPA for acid gas that contains between 40 and 50 per cent H_2S. Over the same size range, plants processing acid gas with very high concentrations of H_2S would be subject to higher recovery requirements under the EPA guideline while for plants processing acid gas containing lower concentrations of H_2S (down to 50 per cent), IL 80-24 requirements would be more stringent. Above 500 t/d sulphur inlet, the EPA requirements are higher for all acid gas streams with greater than 50 per cent H_2S.

QUESTION BY REVIEW COMMITTEE

Clarify BAT and BACT terminology definitions.

RESPONSE

The term Best Available Control Technology (BACT) is defined by the United States Environmental Protection Agency in its Clean Air Act as

> "...an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from, or which results from, any major emitting

> facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of "best available control technology" result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to Sections 111 or 112 of this Act (Section 169(3))."

In Alberta, BAT is Best Available Technology. It is generally taken to mean the one best technology that has a reasonable likelihood of working. It may include new technology or technology that is not completely proven. Cost is a secondary factor.

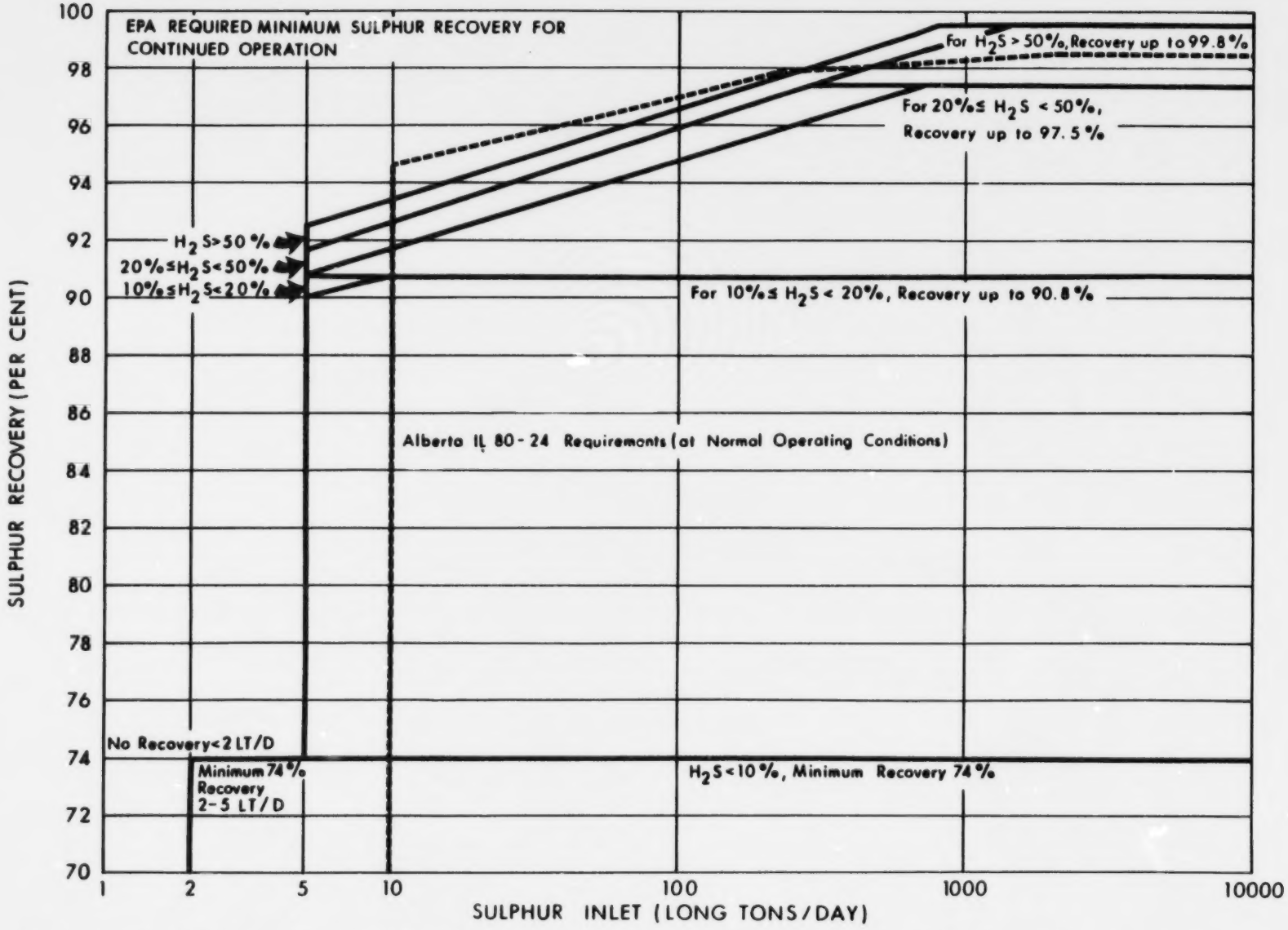
QUESTION BY CONCORD

> **On page 16 - "net annualized capital and operating costs were important factors in the TACB determination of BACT. Annualized costs of up to $2,000 US/t of sulphur abated... viewed by the TACB as representing a reasonable level of control technology." How does this value compare with annualized capital operating costs for a new plant in Alberta applying under IL 80-24, for example, for a 50, 350, or 2500 t/d S-inlet rate?**

RESPONSE

In order to calculate the marginal costs of meeting IL 80-24's requirements for the three cases requested, it is necessary first to establish a base recovery level for each case. This base is the recovery level that would be met in the absence of an increased requirement such as IL 80-24. For Alberta, we believe it is reasonable to assume that this base is the requirements described in the 1971 guideline for sulphur recovery. The assumptions made regarding recovery levels and technology are shown in Addendum Table 5-1 along with the calculated pre-tax net revenues corresponding with each recovery level and marginal costs.

The reader is cautioned about making direct comparisons between these marginal cost figures and the TACB's 2000 $/t figure without knowing the base to which the 2000 $/t corresponds and the details of the calculation itself.



ADDENDUM FIGURE 5-1 COMPARISON OF U.S. EPA NEW SOURCE PERFORMANCE STANDARD FOR ON-SHORE GAS PRODUCTION INDUSTRY WITH ALBERTA IL 80-24 REQUIREMENTS

ADDENDUM TABLE 5-1 MARGINAL COSTS OF MEETING IL 80-24

Sulphur Inlet (t/d)	Technology to Meet 1971 GL and (Efficiency, %)	Technology to Meet IL 80-24 and (Efficiency, %)	Marginal Cost of Incremental Recovery ($/t)
50	2-Stage Claus (93)	3-Stage Claus (96.2)	107
350	3-Stage Claus (96.2)	Sub-dewpoint Claus (98.6)	N/A[a]
2 500	Sub-dewpoint Claus (98.8)	Selective Absorption TGCU (or equivalent) (99.8)	715

a Our analysis shows a negative marginal cost for this case indicating that the value of the additional sulphur recovered more than offsets the increased capital and operating costs.

QUESTION BY CONCORD

What are the S-recovery guidelines used in France, Germany, and Japan for sour oil (refineries) and gas plants? Are the guidelines related to the net annualized capital and operating cost as it is for the TACB?

RESPONSE

It is our view that recovery guidelines for refineries are not particularly relevant to this review. While sulphur recovery and tail gas clean-up technology employed at refineries is in many cases similar to that used in the sour gas industry, other factors such as economics, location, and scale of operation are so different for the two industries that a comparison of sulphur recovery requirements would not mean very much.

Restricting ourselves to sour gas processing only, we concluded that this industry exists in France and West Germany but not in Japan. Our information source for this is a survey of world-wide sulphur production from the oil and gas industry undertaken annually by the Oil and Gas Journal. As noted in the Task Force Report, we asked the French Government for information regarding sulphur recovery rules in France during our initial survey of other jurisdictions. The French Government did not respond and we have not followed up on the matter. We understand that there is one sour gas processing plant in France that recovers sulphur, a very large one operated by Ste. Nationale Elf Aquitaine (SNEA). This plant employs subdewpoint tail gas clean-up technology that was developed by SNEA. One would expect the recovery efficiency for the plant to be in the order of 98 to 99 per cent. It is our understanding that the government does not require any minimum sulphur recovery levels.

For West Germany, we have not tried to contact any government officials regarding sulphur recovery rules. We are aware, however, that there are two large and one medium size sour gas plants that recover sulphur in West Germany. We do not know the vintage of these plants or the technology in place for sulphur recovery.

APPENDIX A

TASK FORCE UNDERTAKINGS FROM REVIEW COMMITTEE MEETING

TASK FORCE UNDERTAKINGS

The Task Force agreed to:

1. Provide a list of economic parameters considered in the report if the representative for the industry members of APIGEC (industry group) identifies what specific data is wanted.

2. Provide data on the incremental reduction in sulphur emissions associated with the two proposed sulphur recovery levels over the forecast period.

3. Address question 9, page 2, of the industry group's 2 October 1986 letter in writing. (This pertains to correlation of sulphur emission data discussed in various sections of the Task Force Report.)

4. Provide raw data used to determine reduction in sulphur emissions from 1972 to 1985 (see industry group question 10, page 2).

5. Compare EPA sulphur recovery guidelines and IL 80-24. Clarify areas where EPA guideline is higher than IL 80-24 and where IL 80-24 is higher than EPA.

6. Review the various sulphur recovery technologies described in the report and split out those which are considered available technology compared to proven technology.

7. Expand report in areas that discuss acid gas quality. Draw up trends of acid gas quality in province. Plot new plants since 1980 and include acid gas flaring plants.

8. Do sensitivity studies on the impact of different product prices. The Industry and Special Interest groups each agree to provide alternative price scenarios to the Task Force.

9. Investigate and comment on environmental cost and impact of disposal of non-saleable sulphur (re: question 5, page 8 of industry group letter).

10. Write out assumptions used in determining capital cost of various sulphur recovery processes (re: question 8, page 5 of industry group letter).

11. Evaluate the seven plants built since 1981 and provide data on actual plant load factors (re: question 9, page 5, of industry group letter). Industry to provide its estimates of load factors so Task Force can do sensitivity studies on the impact of different load factors.

12. Look at more factors in re-evaluating the economic analysis for plants considered in the 1 to 5 t/d sulphur recovery range discussed in the report.

13. Clarify BAT and BACT terminology definitions.

14. Provide a copy of SKM's written comments on the draft Task Force Report.

15. Make available all computer economic evaluation runs.

16. Clarify the intent of the de facto line on the graph on page 59 of report.

APPENDIX B

SPECIAL INTEREST GROUP QUESTIONS

Concord Scientific Corporation

2 TIPPETT RD., TORONTO, ONTARIO, CANADA M3H 2V2 TELEPHONE: (416) 630-6331

October 20, 1986

CSC File: J858

Mr. Harry Webber
Manager, Gas Department
Energy Resources Conservation Board
640 Fifth Avenue, S.W.
Calgary, Alberta
T2P 3G4

Dear Harry:

Subject: Revisions to Guidelines for Sour Gas Plants

The enclosed list of questions is submitted on behalf of the Special Interest Group Representatives in connection with the Task Force report on revisions to guidelines for sour gas plants. Your prompt attention would be much appreciated.

Yours truly,

CONCORD SCIENTIFIC CORPORATION

Harry Spano

for HARRY CLEGHORN, Ph.D
Senior Industrial Chemist

HC:mcs

Enc.

cc: Dr. Martha Kostuch
Mrs. Sophie Taylor
Mr. Marvin Prusky
Mr. Graeme Bethell

Questions Arising from the Task Force Review on Revisions to the Guidelines for Sour Gas Plants

1. Figure 1-2 shows a total of 161 plants covering all sizes. Please confirm that this is the total for the Province.

   Are all 161 plants operating under IL80-24 guidelines? If not, how many are not? Please provide a full break-down of the following parameters for each plant:
   - plant size (inlet sulphur)
   - % S-recovery
   - location
   - projected life

2. Please supply a plot illustrating allowable SO_2 emission rate (TPD) vs stack effluent flow rate as M^3 per day.

   Illustrate on the graph comparison plots for:
   - sour oil processing facilities
   - coal and coke burning facilities
   - other, e.g. sulfuric acid plants

   Please supply a plot illustrating maximum allowable H_2S, COS and CS_2 emission rate vs stack effluent rate.

3. Please superimpose an illustrative plot for Figure 1-3 that includes processing of ultra-high H_2S gas.

   Figure 1-3 refers to existing and future plants under IL80-24. Please superimpose a plot that includes S-emissions from existing plants not covered by IL80-24.

4. What are the sizes for each of the 8 plants in the 1000 - 5000 TPD sulphur inlet? (Figure 1-2).

5. On page 16 - "net annualized captial and operating costs were important factors in the TACB determination of BACT. Annualized costs of up to $2,000 US/t of sulphur abated... viewed by the TACB as representing a reasonable level of control technology." How does this value compare with annualized captial and operating costs for a new plant in Alberta applying under IL80-24, for example, for a 50, 350 or 2500 TPD S-inlet rate?

6. What are the S-recovery guidelines used in France, Germany and Japan for sour oil and gas plants? Are the guidelines related to the net annualized capital and operating cost as it is for the TACB?

7. On page 33 it is assumed that direct oxidation processes are considered to be the least costly to apply and are capable of achieving the highest S-recovery levels. Please illustrate in a table comparison costs (capital and operating) for direct oxidation processes with other representative processes. Illustrate costs for 50, 350 and 2500 TPD S-inlet examples.

8. Please test the sensitivity of the model to variations in the following input data. For calculation puposes, consider each variable independently.
   - product prices increase at 2.5 - 7.5 % per year.
   - fixed and variable operating costs increase at 2.5 - 7.5 % per year.
   - initial year's production held constant for 3 years, increased by 5% in the 4th year, held constant to 6th year, then reduced by 5% in the 7th year, and by 10% of a declining balance after. (Examine for 50, 350 and 2500 TPD S-inlet ceses and recalculate ROR's in Table 4-5 for these cases.)

9. Are the assumptions on page 33 the only assumptions used in the model? If not, please provide details.

10. Please supply a copy of the SKM Consulting Ltd. Report.

11. Please supply a copy of the MHG Report.

12. What are the correct data for columns 3 and 4 in Table 4-7?

In addition to answers to the above-listed questions, we would like to have copies of answers supplied by your office to all other participants in the review process.

H.P. Cleghorn
October 20, 1986

APPENDIX C

APIGEC QUESTIONS

Amoco Canada
Petroleum Company Ltd.
Amoco Canada Building
444 Seventh Avenue S.W.
Calgary, Alberta T2P 0Y2

November 4, 1986

86294ACC0071

W. Schnitzler
Energy Resources Conservation Board
640 - 5 Avenue S.W.
Calgary, Alberta
T2P 3G4

Sulphur Recovery Guidelines for Alberta Gas Plants; File: RJD-023.507.4

Further to the meeting on October 3, 1986 and H. J. Webber's letter of October 15, 1986, it is requested that the following economic sensitivities be run comparing IL 80-24 as issued with the proposed guidelines:

1. Using published refinery and pipeline cost indexes, increase the capital investment from the 1981-82 estimates to current (1987) values.

2. Increase the capital investment by 50% to cover exploration costs which might approximate full cycle economics.

3. Reduce the plant load factor's to 65% and 50% to better represent actual situations.

4. Reduce product prices to current levels with prices held constant for two years increasing at 5% per year through the project life. APIGEC would like confirmation of the current prices that will be used.

5. We would like to reserve comment on the capital costs until data from the Task Force on capital investment (item 10 in the October 3 meeting minutes) is available.

6. Additional detail on operating cost assumptions and, in particular, the treatment of fuel gas in the analysis is also requested.

Two additional items should be included in the "Comments on Direction of the Guideline Review" section of the draft minutes. As indicated in our opening statement at the October 3, 1986 meeting, given the negative economics of increased sulphur recovery and the reduced product prices,

reduced plant throughputs and the marginal nature of new sour gas development, industry questions the appropriateness of proceeding with the review at this time. A comment along these lines should be included. The "de facto line" used by the Task Force to reflect current sulphur recovery requirements created a great deal of confusion and misrepresented the current IL 80-24 guidelines. A comment relating industry's concerns on this matter should also be included in the same part of the minutes.

In addition, we would like to receive a copy of the SKM Consulting report which was referred to in the Task Force report.

The APIGEC Industry Technical Subcommittee members strongly suggest an amended report be issued following completion of the economic sensitivities, and other work which the Task Force agreed to do.

R. J. Dreveny /BDR

R. J. Dreveny
Chairman, APIGEC Industry Technical Subcommittee

BDR/mal

cc:
J. S. Moore, Chairmain, APIGEC Industry Committee
H. J. Webber, Energy Resources Conservation Board

APPENDIX D

IPAC QUESTIONS

SCEPTRE RESOURCES LIMITED

2600 Bow Valley Square 4, 250 - 6th Avenue S.W., Calgary, Alberta, Canada T2P 3H7
Telephone: (403) 298-9800
Telex: 03-822619

HAND DELIVER

October 22, 1986

Energy Resources Conservation Board
640 - 5th Avenue S.W.
CALGARY, Alberta
T2P 3G4

Attention: Mr. E. Moeller
Gas Department

Dear Sir:

Re: Review of Sulphur Recovery Guidelines

In response to H. Webber's letter of October 15 regarding the Task Force review please find attached my comments and questions presented at this review on behalf of IPAC. I also raised the question "What effect will the change in guidelines have on the sulphur industry of Alberta, ie: with regard to further drilling in sour gas prone areas, taking into account most of Alberta's sulphur inventory will be gone by 1990?". This question was not addressed by the Task Force and we believe it should be.

I believe G. Daviet of Dome Petroleum will also supply you with his questions.

If you require any further information please contact me directly at 298-9763.

Yours truly,

SCEPTRE RESOURCES LIMITED

T.W. Dickson
Vice President, Engineering

cc: G. Daviet, Dome Petroleum
R. Hillary, IPAC

IPAC Position On Task Force Report

IPAC appreciates the opportunity to address our concerns on the Task Force Report. Unfortunately IPAC only received the report a few days ago and in fact only picked its representatives two days ago. We therefore have not compiled a detailed technical review but can give some general observations from reading the report.

IPAC represents the small, medium and large independent exploration and production companies who now do the bulk of exploration in Alberta. This exploration effort has been shifting westward towards the foothills into areas where the chance of a sour gas discovery is greater and thus the concern for having added financial obligation placed upon the industry that will not encourage exploration in this important region where future discoveries could help maintain Alberta's reserve position (ie: replacement of present production).

Concerns

1. Environmental

The main concern is not including the impact of SC_2 emission on the environment in the terms of reference. How can additional non economic expenditues be justified if it cannot be proven that society would even benefit. It is IPAC's position that until such studies as stated in your introduction are completed and reviewed; the Task Force report should be put on hold. It is imprudent to add further burden to the industry at a point when cash flows have been halved by the present oil price slide and where gas price slide will further erode cash flow, unless some documented evidence can be given to support the more stringent air quality requirements which by your admission are among the highest in the world now. We would further state that 1980 recovery changes were not supported by evidence of damage to the environment and thus at the conclusion of the studies the entire guidelines should be re-examined.

2. Economics

a) The non inclusion of exploration costs in your rate of return calculation is misleading to the public. These figures indicate very high after tax ROR of double or more of bank interest. You admit that risk has to be applied yet you did not apply it. As Alberta exploration is in a mature state, the discoveries are smaller (1-3 wells, 5-20 BCF) of 1-10% H_2S gas. These require detail seismic work and complex geological examination, which is a significant portion of most projects, plus the proportionate cost of drilling dry holes. We would suggest that the after tax R.O.R. could be lowered 5-10% (before sulphur plant addition) to a rate closer to "bank rates" and then if the differential R.O.R. for sulphur recovery is taken off then the R.O.R.could be below the bank rate of 10%. This would of course depend on the success ratio of a company, remoteness of the area, reserves found, etc. which really means it is very dangerous to present a typical case - What is typical?

b) Percentage difference should be presented

Example 1) ROR difference for 1 t/d is 25% versus 17% for 50 t/d and 8% for 1000 t/d (Table 4-5)

Example 2) Difference of pre tax revenue (Table 4-6)
Revenue percent difference for 1 t/d is 39% versus 22% for 10 t/d, 6% for 1000 t/d
(also see attached cost indicators)

c) Concern over amount

Page 37 Paragraph 2:
$5MM may not be missed - is a very dangerous statement in these times

d) Price

$1.60/GJ - not in todays deregulated world - Price @ WH of $1.00 - $1.25/GJ is more normal, at least for the present and probably for as long as surplus test exists.

$29/bbl condensate? - We believe $20 is more realistic.

Sulphur prices have also dropped 8-10% over the last two months on export markets and sulphur block recovery slowed although in the long run prices may hold. We would like more detailed information on economic cases.

e) Load factor of 85% is very high. Most contracts require 20-25% additional deliverability to be available for peak days. We suggest a load factor in the 70-75% range to be more realistic (perhaps look at actual plant statistics).

Conclusion

It is obvious the main economic impact is on the 1-10 (even 50) t/d plants. These are typically the size built to service the smaller sour gas reservoirs found today. Typically if a discovery is made, an operator would try to find a market (difficult at best) then go to the nearest facility to tie-in. If his sour gas adds 25% H_2S to an existing facility the owner would not let him in. Thus he is left to decide whether or not to build his own plant (clearly not justified from an overall economic sense in that the existing plant is under-utilized - as in the case with many plants today) which would be economically marginal at best. Therefore the gas will probably go undeveloped and in the future less exploration will be carried out in these regions. Alberta is the loser in both loss of capital expenditure thus loss of jobs, and reserves not being maintained. The end result will see very few plants being built in the 1-10 t/d range (which by your graph now only emit 7.5% of all SO_2 into the atmosphere) causing a shift of capital and jobs away from Alberta.

COST INDICATORS

Plant Size t/d Sulphur	Additional Costs Capital/t M$	Additional Costs Operating/t M$
1	470	159
2	415	112
5	320	64
10	250	60
50	92	10
350	52	7

APPENDIX E

SKM REPORT

SKM Consulting Ltd.

No. 826, 205-9th Avenue S.E.
Calgary, Alberta T2G 0R4
Tel. (403) 233-9400

July 31, 1986

Energy Resources Conservation Board
640 - 5 Avenue S.W.
Calgary, Alberta T2P 3G4

Attention: Mr. W. J. Schnitzler

Gentlemen:

This letter is to advise that R. S. Geddes and K. C. Milne have completed their review of Sections 3 and 4.3 of the Sulfur Emission Guidelines Report and have concluded that:

- There are no significant errors
- No process of significance has been missed
- The capital and operating costs set out in Section 4.3 are reasonable

Yours very truly,
SKM CONSULTING LTD.

K. C. Milne

R. S. Geddes

KCM/pmb
Attach.

QUESTIONS AND COMMENTS ON

SULFUR EMISSION GUIDELINES REPORT

1. On Page 9 of Section 4.3 - "...assumed to operate at 85% of capacity...". In our opinion this is a high operating rate based on recent and/or historical experience.

2. We understand that the sulfur recovery levels listed on Table 4-1 are "design" sulfur recovery efficiencies reduced by a factor (0.5% for MCRC and 0.2% for Oxysulfreen or Sulften) to allow for periodic variation from ideal conditions. This factor does not include the 0.3% reduction allowed on a quarterly basis to allow for "upset and bypass conditions".

   You will recall that our previous report to you on this matter concluded that this factor would range from 0.7% to 1.0% for a two stage Claus plant with a sub-dewpoint reactor.

   Therefore, the factor of 0.5% for the MCRC process will mean that sulfur plant operators will be required to make some investments to improve on the operation of existing two-stage Claus plants (such as improved control instruments and more frequent catalyst changes .

   Because a commercial oxysulfreen process has not yet been built, and only one Sulften process has been built, it is difficult to evaluate the suggested factor of 0.2%. However, it is our judgment that it may prove to be low.

   It is also our opinion that the "design" recoveries proposed for the MCRC process are high unless one assumes that revisions are made to the front end of the sulfur plant in order to reduce COS and CS_2 to a negligible level.

   A recent publication suggests that Amoco's Ultra process has a design recovery efficiency of 99.7%. If this is valid, there is a good argument that the oxysulfreen process should not be rated higher than 99.7% since it has not yet been piloted which the Ultra process has.

3. It should be noted that tail gas cleanup processes that use hydrogenation followed by selective absorption may be more costly than hydrogenation followed by a Direct Oxidation process (such as Stretford) where the acid gas is 50:50 rather than 80:20. In particular, Shell consider the Scot process to be not suitable for low H_2S acid gas and we believe this may also be the case for Sulften if the CO_2 pickup is as stated in literature.

4. It is suggested that generic names be used for the processes listed in Table 4.1 rather than trade names.

5. Some processes that were not included are the following:

   - Shell Flue Gas Desulfurization (1 Commercial Unit)
   - Westvaco (Development Stage)
   - Lucas (one prototype built in 1976 replaced by Selectox)
   - Magnesium Oxide (used on flue gas)

   We do not believe that the report would be affected whether or not these processes are included.

6. Some direct oxidation processes have produced saleable sulfur (Stretford unit at Long Beach).

7. In normal sour gas processing plant operations additional medium and low pressure steam is a cost (needs to be condensed) rather than a savings. In your economic analysis you should consider giving credit only for high pressure steam.

8. Costs in the MHG report were 1982 while costs in the SKM report were adjusted to 1983.

9. On Table 4-4 the 350 t/d capacity would require about 25% H_2S rather than 20%. May be a typo.

10. Cost of the 50 t/d Sulften plant for 80:20 acid gas looks low in comparison with the other costs. Again this may be a typo.

11. Capital costs for sulfur forming and handling are reasonable for small plants with normal loading facilities and for large plants with 8 hour unit train loading facilities.

12. Note that operating labour (and other miscellaneous operating costs except maintenance) for sulfur handling has not been included in operating costs.

13. It is suggested that the cost of an incinerator and stack should be included in the Sulften costs since it has been assumed (Page 31 of Section 3) that the incinerator will be operated in a standby mode.